# Coupled Thermal Hydraulic Mechanical and Chemical (THMC) Modeling of the GreenLoop system in the Southeast Geysers, California

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**Keywords**

*Steam and 2-Phase GreenLoop, Closed-Loop Geothermal, The Geysers, Downbore Heat Exchanger*

**ABSTRACT**

GreenFire Energy Inc. (GFE) has been developing a technology for the application of closed-loop geothermal (CLG) technology in steam-dominated and high-enthalpy two-phase reservoirs (called Steam 2-Phase GreenLoop (S2PGL)) for several years. Details on the coupling of thermal, hydraulic, mechanical and chemical (THMC) modeling of the S2PGL system with focus on factors such as heat transfer, phase change, temperature, fluid flow, mineral alteration, fluid chemistry, and seismic activity have been illustrated. The simulation was conducted for a well in the Southeast Geysers area using TOUGH-REACT and TOUGH-FLAC. The Downbore heat exchanger (DBHX) model in the simulation was calibrated with GFE's DBHX model and was found to be in good agreement. Gravity drainage of condensate in the well fills the lower 60-80 meters of the well and flows by gravity and imbibtion into the surrounding unsaturated reservoir rock. The net changes in porosity were found to be minor over the period of simulation/testing and are therefore not expected to impact the S2PGL testing. The THM analysis indicates minor geomechanical impact of the S2PGL operation because temperature and pressure changes are minor in the host rock. The most substantial geomechanical changes are expected to occur at the bottom of the injection well as a result of local cooling, but of smaller magnitude than typical conventional geothermal operations.

## 1. Introduction

GFE has been focused on tailoring solutions to specific geothermal resource characteristics so as to optimize the heat extraction from the resource in a sustainable fashion. One such tailored solution of GFE, the S2PGL is currently being implemented as a proof of concept test project (test project) in the Southeast Geysers area with funding from the California Energy Commission (CEC) in a project to prove its commercial feasibility (Scherer et al., 2022). This project aims to establish a proof-of-concept test in a well owned by Geysers Power Corporation, a subsdiary of Calpine Corporation, with the underlying objective of deploying the technology in a larger scale at The Geysers known geothermal resource area (KGRA). The testing period for the system is expected to be about 3 months.

The S2PGL system at The Geysers consists of a tube-in-tube downbore heat exchanger (DBHX) inserted into a well. The tube-in-tube system consists of vacuum insulated tubing that is contained within an outer casing. The material of the outer casing is typically designed based on the near-wellbore/resource fluid chemistry. The S2PGL system can have variations too as covered in prior research (Amaya et al., 2021; Higgins et al., 2021).

Depending on the specific application/end use of the heat from the S2PGL system, a working fluid for the DBHX can be selected. Details on the comparative analysis between multiple working fluids is covered in Chandrasekar et al. (2023). In the case of the DBHX in the Southeast Geysers test well, water was chosen as the working fluid. The flow direction within the DBHX can either be forward or reverse. Forward flow refers to injection of the working fluid through the center insulated tubing and production of the working fluid through the annular region between the outside of the insulated tubing and the outer casing of the DBHX. On the other hand, reverse flow refers to the injection of working fluid through the annular region and production through the center insulated tubing. Both forward and reverse flows are expected to be tested for substantial time periods in the test project; however, this paper only covers the simulation results considering the reverse flow operating condition.

Besides flow inside the DBHX, there exists an additional fluid loop on the outside of the DBHX in the near wellbore region. The steam enters the wellbore through its perforated liner from the resource and interacts with the relatively colder outer surface of the DBHX resulting in condensation. The latent heat of vaporization is extracted by the DBHX and captured in the working fluid. The resource fluids (in liquid state) flow downwards by virtue of having a higher density than steam and the hydrostatic pressure of the fluid column causes the fluid to recharge back into the resource. Prior to and during recharge, the condensate will contact the DBHX and casing metals. The chemistry of the condensate impacting the DBHX, casing materials and the resource rock are assessed in this paper using reactive-transport simulations of water chemistry changes owing to the rock-steam-water interaction and acid gas transport. Non condensable gases (NCG's) are either vented at the surface (if their concentrations are high) or, if very substantial, may power a surface heat exchanger to make additional power. Due to the counter flow, as the NCG's approach the surface, they cool and lose humidity until they are produced relatively dry at the surface.

The geomechanical changes in the resource as a result of cooling around the heat exchanger are also rigorously modeled to estimate the expected stress changes and possible increases in the fracture apertures.

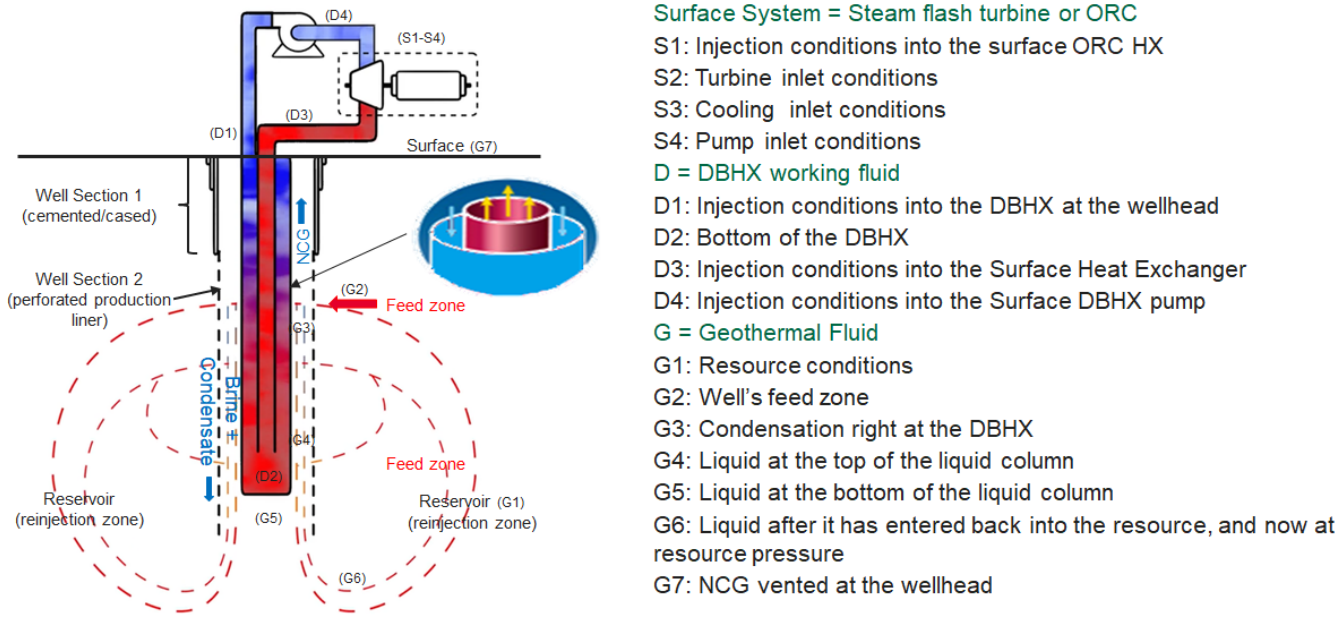


**Figure 1: Schematic of the S2PGL system with a DBHX tube-in-tube configuration (i.e., a vacuum insulated tubing contained within an outer perforated liner casing) inserted within a geothermal wellbore. Various subsurface and surface components that are pivotal for the operation of the technology are also labeled and shown in the figure. Non-condensable gases are shown venting at the surface as they flow between the outer casing of the DBHX and the casing of the wellbore. The figure shows the reverse flow operating condition within the DBHX (cold fluid entering the annulus and hot fluids exiting through the center of the vacuum insulated tubing). The figure is adapted from Scherer et al. (2022).**

## 2. California Energy Commission Support

GreenFire was awarded a $2,705,228 grant by the California Energy Commission (CEC) to advance the development of GreenFire's Steam Dominated GreenLoop (SDGL) system in an existing low-production geothermal well at The Geysers geothermal area in Lake County, California (GreenFire Energy, 2022). The award (EPC-21-015) came from the CEC's Bringing Rapid Innovation Development to Green Energy (BRIDGE) funding opportunity, which competitively selects and awards follow-on funding for the most promising clean energy technologies that have previously received an award from an eligible CEC program or United States federal agency. GreenFire's previous CEC project (GEO-16-004) that retrofitted an existing well and conducted tests with a DBHX at Coso, California was referenced to support award selection.

BRIDGE seeks to 1) help start-up companies minimize the time between when their successful publicly funded project ends and new public funding becomes available; and 2) mobilize more early-stage capital in the clean energy space by providing non-dilutive, matching investments in promising clean energy companies alongside investors and commercial partners. This provides increased support for the most promising clean energy technologies that have already attracted interest from the market as they are developed and continue their path to market adoption.

BRIDGE is part of the CEC's Electric Program Investment Charge (EPIC) program – a public interest research and development program that invests in scientific and technological research to accelerate the transformation of the electricity sector to meet the state's energy and climate goals. The EPIC program invests more than $130 million annually to help:

- Expand the use of renewable energy.
- Build a safe and resilient electricity system.
- Advance electric technologies for buildings, businesses, and transportation.
- Enable a more decentralized electric grid.
- Improve the affordability, health, and comfort of California's communities.
- Support California's local economies and businesses.

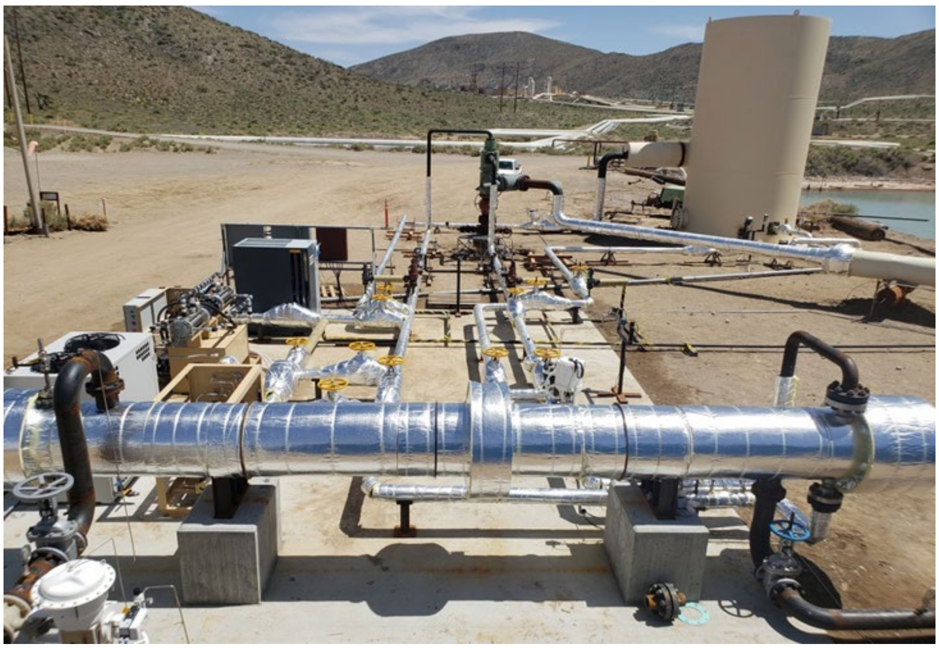

**Figure 2: The layout of surface equipment along with wellhead modifications that were required for the demonstration project conducted by GreenFire Energy at Coso, California. The project was funded by the California Energy Commission.**

## 3. Modeling Methodology

A thermal-hydrological-mechanical-chemical (THMC) model was developed as a part of the project to analyze and predict the behavior of the wellbore and the near wellbore region over the period of the testing (before the actual installation of the system in the wellbore). The model was primarily developed using LBNL's multiphase reactive-transport and geomechanics simulators TOUGH-REACT, TReactMech (Sonnenthal et al., 2021; Xu et al., 2011; 2006), and TOUGH-FLAC (Rutqvist et al., 2002; Rutqvist, 2011; 2017; Rinaldi et al., 2022). The thermal hydrological wellbore simulator implemented for the closed loop of the DBHX of the multiphase transport model was also compared with GFE's proprietary S2PGL DBHX model. Greater detail on GFE's S2PGL modeling methodology can be found in Higgins et al. (2021). The following paragraphs details the various steps undertaken for the simulation.

First, a 2-D axisymmetric mesh was developed and generated to simulate the native-state model (at steady state) of the wellbore in the Southeast Geysers area capturing the observed depth of the liquid cap and steam zone as well as the approximate reservoir pressures and temperatures. Appropriate permeabilities were assigned to various rock layers adjoining the wellbore which include the cap rock section and the reservoir sections. A high permeability zone or feedzone was also assigned to the grid at an appropriately observed depth. The DBHX was modeled with a casing outer diameter of 7.625 inches. Thermal conductivities (wet and dry) along with densities and specific heat capacities were assigned to various rock layers, well casing, DBHX casing and the vacuum insulated tubing. Van Genuchten correlations were employed for modeling the capillary pressures and the relative permeabilities, based on earlier modeling studies of the Geysers area (Dobson et al., 2006).

TReactMech introduces a parallel coupled continuum geomechanics capability into the THMC parallel simulator TOUGHREACT V4.13-OMP (Sonnenthal et al., 2021; Xu et al., 2011); with improvements to the TOUGH2 multiphase flow core (Pruess et al., 1999). The geomechanical formulation is based on a continuum finite-element model with stress calculations (Smith et al., 2022; Kim et al., 2012). Geomechanics are solved after fluid and heat flow, followed by transport of aqueous and gaseous species, mineral-water-gas reactions, and finally permeability-porosity-capillary pressure changes owing to geomechanical and geochemical changes to porosity (or fracture aperture). For the reactive-transport simulations we used the TOUGHREACT v4.13 reactive transport core of the simulator (i.e., no geomechanics).

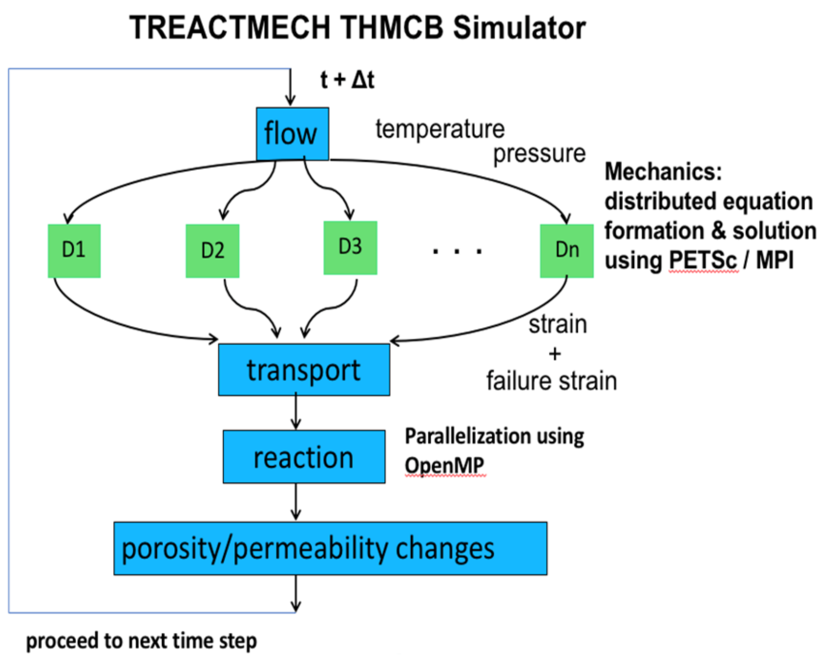


**Figure 3: Heat and fluid flow, stress, and reactive transport are solved using the sequential non-iterative approach in TReachMech as shown. Fluid flow and heat transport are solved simultaneously with modifications to consider multiple coupled geochemical and geomechanical effects on porosity and permeability, as well as new capabilities such as temperature-dependent thermal properties. Geomechanics are solved using Petsc/MPI and reactive chemistry with OpenMP (TOUGH-REACT core).**

The coupled multiphase fluid flow, heat transport and geomechanics was in this case simulated with the TOUGH-FLAC simulator, that links TOUGH2 or TOUGH3 multiphase flow and heat transport simulators with the FLAC3D geomechanical simulator (Rutqvist et al., 2002; Rutqvist, 2011; 2017; Rinaldi et al., 2022). The TOUGH-FLAC simulator has been extensively applied to The Geysers system associated with the Northwest Geysers EGS Demonstration Project (Garcia et al., 2016; Rutqvist et al., 2016).

## 4. Results and Discussions

The findings and discussions have been divided into three distinct sections namely: Thermal-Hydrological (TH), Thermal-Hydrological-Chemical (THC), and Thermal-Hydrological-Mechanical (THM) modeling. The results from the TH analysis are used as inputs to obtain the detailed THC and THM models.

### *4.1 Thermal-Hydrological (TH) Modeling*

The liquid velocity vectors in the wellbore and the region very close to the wellbore (about 2 m away) are shown in the figure below through streamlines (Figure 4). The arrows indicate the direction of the flow in the wellbore/near wellbore region. The figure captures the effect of condensation and the resultant density differential that is created while operating the S2PGL system at a specific flow rate. The liquid saturation is high as the fluid reaches towards the DBHX bottom (about 1460 m), post which the saturation decreases since the fluid begins to gain temperature during the downflow within the wellbore.

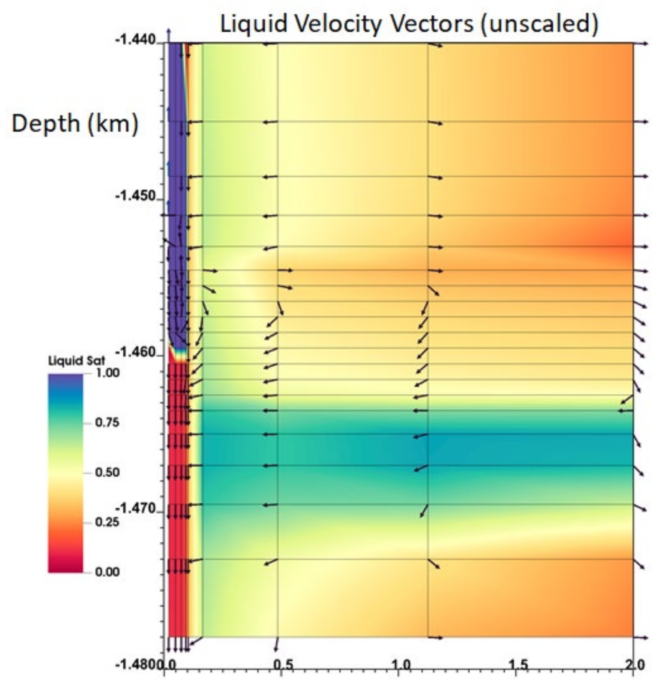


**Figure 4: Liquid velocity vectors represented in the radial and axial coordinates (radial distance in m versus Depth in km). The figure also represents the liquid saturation in the wellbore and the near wellbore region. The near wellbore region right below the DHX at about 1.465 km shows a high liquid saturation due to the effects of capillarity. The X axis scale is from up to 2 m and the Y axis scale is from 1.44 km to about 1.48 km.**

The figure below (Figure 5) illustrates the liquid saturation in the wider vicinity of the wellbore (50 m away from the DBHX). It also displays the saturation profile spanning the entire wellbore and extending beneath it for a particular flow rate within the DBHX. It can be observed that the liquid saturation at the surface when the DBHX is in operation is very low (about 0.1 from the dashed blue line which represented the open well, i.e., the annulus between the DBHX outer casing and the well casing) and that steam is primarily expected to consist of NCG's. Towards the bottom of the well (lower 60-80 m) ponding occurs due to gravity drainage of condensate leading to high liquid saturations. However, beneath the well the liquid saturation is expected to drop rapidly towards the native state of the resource.

It is also observed that the effects of capillarity are minimal and can be observed only up to a radial distance of about 20 m from the bottom of the DBHX. In addition, it is also analyzed that the condensed fluid movement back into the resource in the region right below the DBHX is minimal and the majority of the condensed fluids travel down the wellbore resulting in the ponding effect. Therefore, it is understood that capillarity only plays a minor role in the performance of the system overall.

In the near wellbore region, the liquid saturations are seen to reduce as the radial distance from the wellbore center increases. At the bottom of the DBHX it is observed that there is an increase in the liquid saturation due to the effects of capillarity, however, below the DBHX, it is observed that the liquid saturation quickly drops off to lower levels (cyan, orange and dashed black lines).

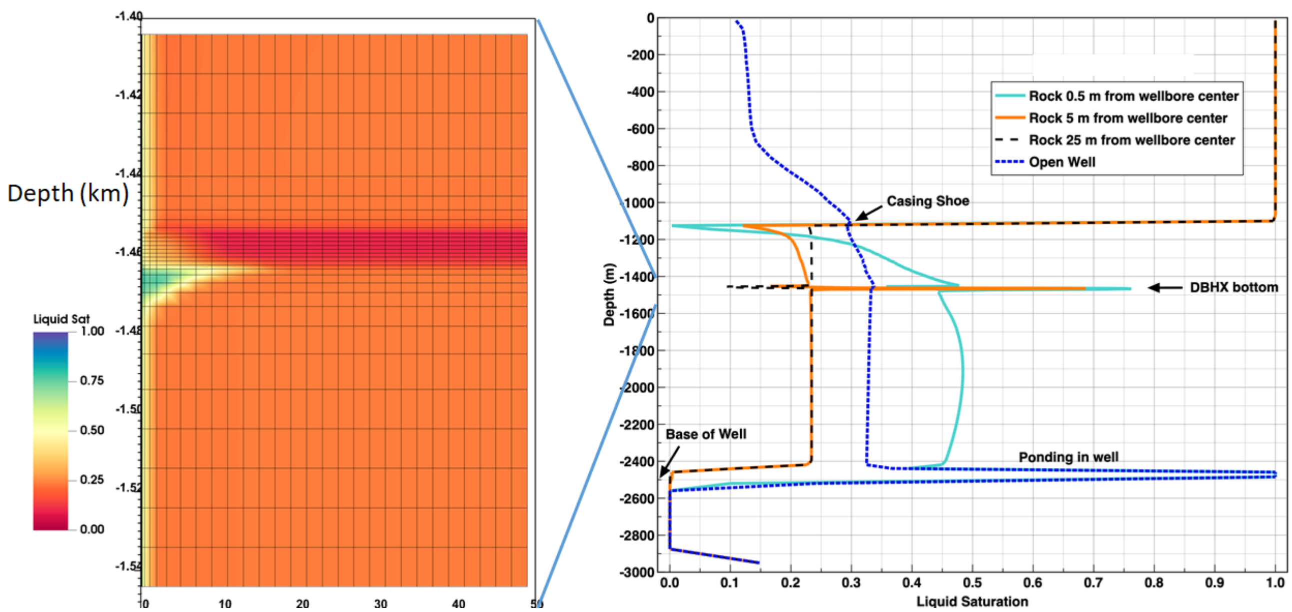


**Figure 5: Liquid saturation in the near wellbore region represented in the radial (in m) and axial coordinates (in km) (left). The effects of capillarity leading to increased liquid saturation can be observed only up to a radial distance of about 20 m. The figure on the left only shows the near wellbore region between depths of 1.4 to 1.54 km. The liquid saturation profiles in the entire wellbore and beneath the wellbore are shown in the figure on the right. The dashed blue line represents the liquid saturation profile in the region between the outside of the DBHX casing and the wellbore casing (open well). The liquid saturations are seen to drop with radial distance as the native state of the resource is reached with increasing radial distance.**

The temperature profile at the base of the well and the DBHX was also analyzed for a particular flow rate in the DBHX as a function of radial distance from the wellbore (Figure 6). The profiles in the figure below are after about 42 days (6 weeks) of continuous steady operation at the selected flow rate. Temperatures in the rock around the base of the DBHX are close to the reservoir temperature owing to the condensed steam flow towards the well. At the base of the well the cooling front has reached nearly its maximum extent from the base of the well from condensate imbibition.

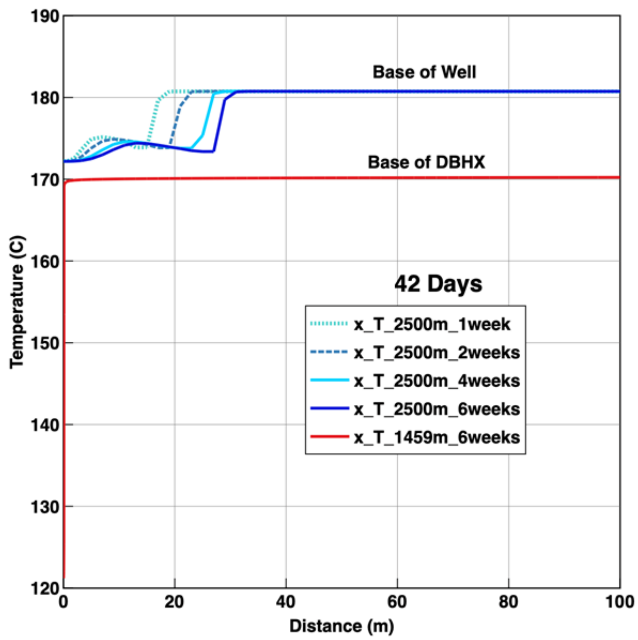


**Figure 6: The temperature profile at the bottom of the DBHX and the base of the well are represented for a particular DBHX flow rate. The temperature at the base of the well has been shown as a function of weeks. With increasing time the native state resource temperature is reached with increasing radial distance.**

### *4.2 Thermal-Hydrological-Chemical (THC) Modeling*

The fluid chemistry at the DBHX was simulated by setting the initial pore fluid chemistry. Information related to the shallow pore water above the caprock was obtained from the Allen Spring thermal-meteoric water composition (Peters, 1993). The pore water conditions for the deeper rock layers (caprock, reservoir, and hornfels) were adapted initially from Wilbur Hot Spring (Donnelly-Nolan et al., 1993) and then equilibrated with reservoir mineral assemblages (Moore et al., 2000). The gas chemistry was calculated through equilibration with the mineral-fluid system.

The figure below (Figure 7) illustrates the pH of the fluids at the bottom of the DBHX and in the wellbore after 6 months of continuous testing at the preferred DBHX flow rate. The condensate is more dilute and has a lower pH in the well.

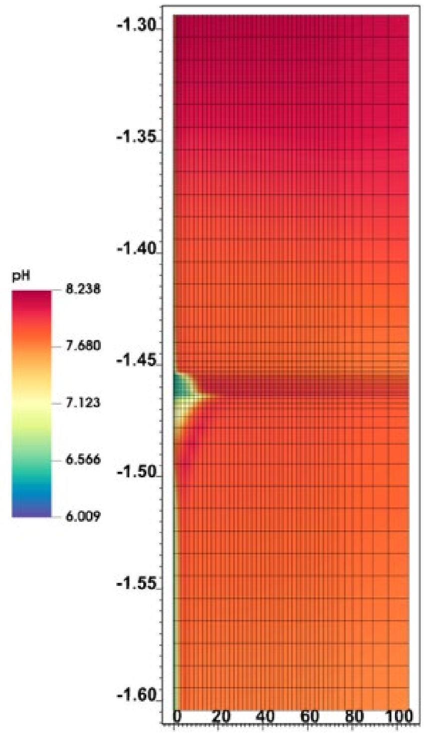


**Figure 7: The profile of pH at the bottom of the DBHX and in the near wellbore region after a period of about 6 months of continuous operation is represented for a particular preferred DBHX flow rate. The condensate is more dilute and has a lower pH in the well and in the near wellbore region. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

$Cl^-$ and $HCO_3^-$ concentrations were also analyzed as a function of radial distance from the wellbore in the figure below (Figure 8). The concentrations of the ions are fairly low near the DBHX but due to boiling of condensate significantly higher concentrations of these ions are found in the near wellbore region.

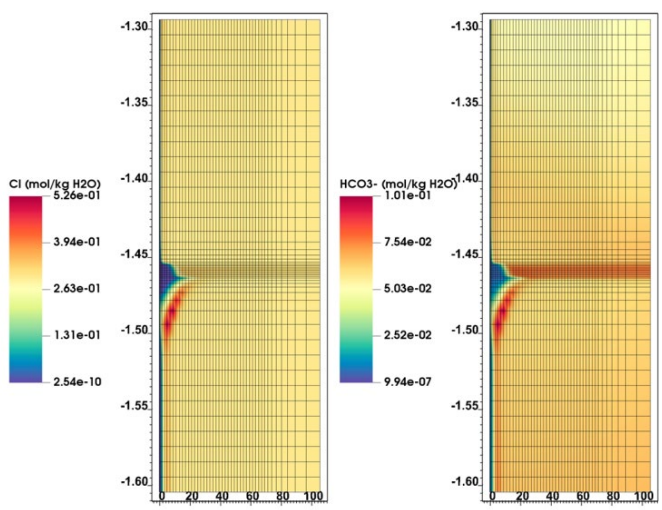


**Figure 8: $Cl^-$ and $HCO_3^-$ ion concentrations in the near wellbore region after a period of about 6 months of continuous operation. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

The $CO_2$, $CH_4$, $H_2S$, and $NH_3$ gas fractions were analyzed and found to vary with steam fraction (Figure 9), however, there was found to be more uncertainty in the well from the low total pressure and high velocity. It was found that the mole fraction of $CH_4$ was a bit higher than $CO_2$. This is primarily because of the fact that gases like $CO_2$, HCl, and HF are scrubbed from the gas into the condensate

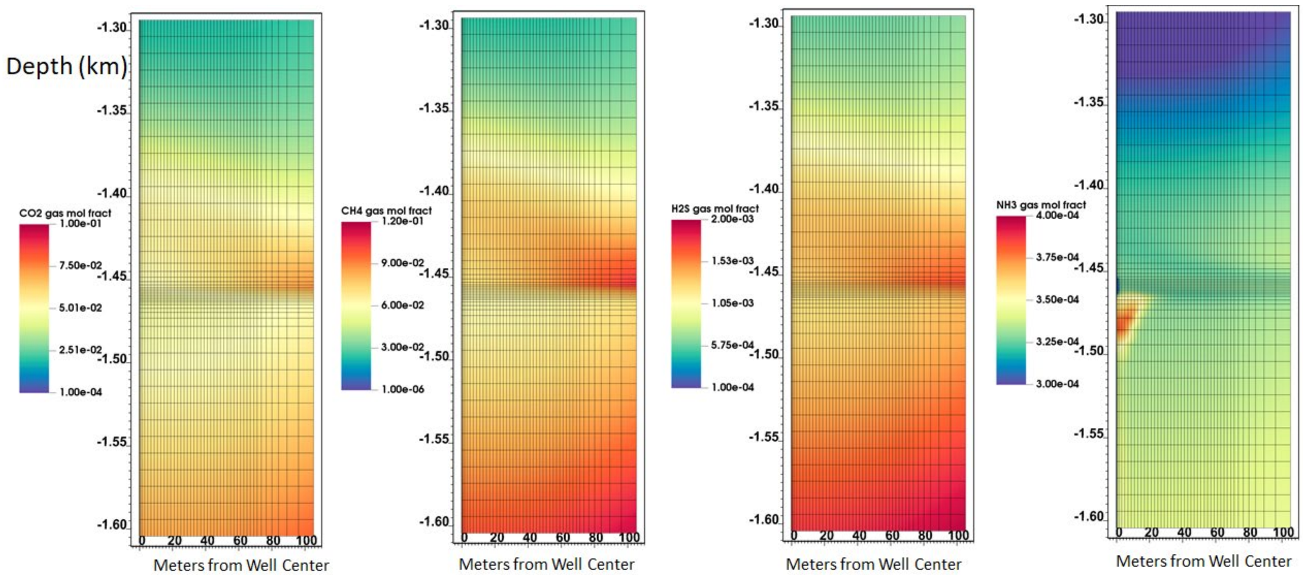


**Figure 9: $CO_2$, $CH_4$, $H_2S$, and $NH_3$ concentrations in the near wellbore region after a period of about 6 months of continuous operation. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

The mole fractions of HCl and HF were in the order of $10^{-14}$ and $10^{-12}$ respectively as shown in the figure below (Figure 10). The compositions of NCG's were simulated in the well at the base of the DBHX after 6 months of continuous operation. The equilibrium gas composition in the well was computed at about 170 ℃.

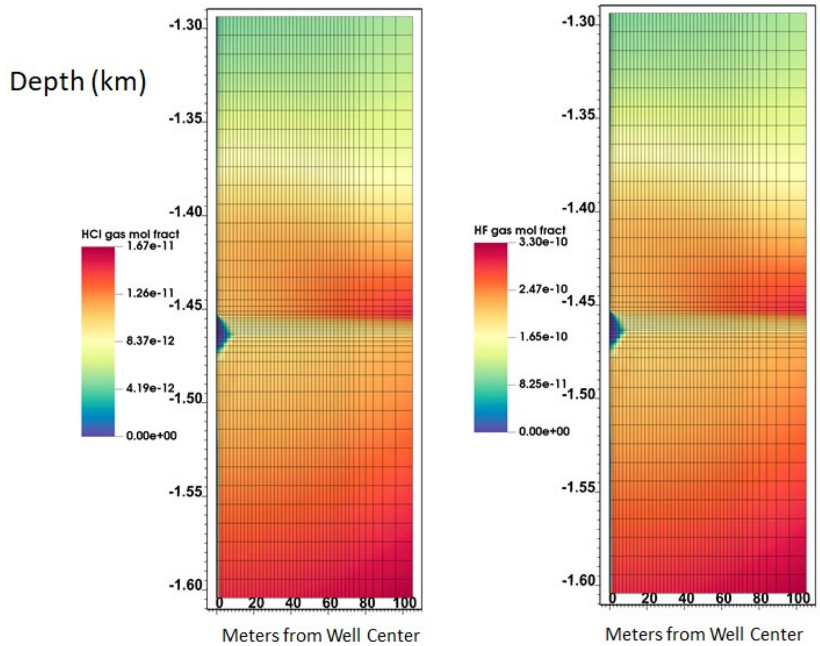


**Figure 10: HCl and HF gas compositions in the near wellbore region are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

It was also found through simulation that boiling leads to higher volume fraction changes for albite, microcline and dolomite in the reservoir at the base of the DBHX. Steam flow and condensate formation also leads to quartz dissolution. However, the order of magnitude volume fraction changes are very low over this time period, given our estimate of the initial water and rock chemistry. This would imply that the expected change in fractures, matrices, and reservoir in general are very low. The only silicate mineral species formed were quartz, albite and microcline since boiling and condensation temperatures are higher than that required for amorphous silica to occur. Therefore, it can be inferred that the risk of silica scaling is very low (it is important to note that the operational saturation temperature required for the S2PGL to function is always higher than the temperatures at which amorphous silica scaling occurs).

For the case of dolomite, the speciation volume fraction changes show a lower precipitation because of inverse solubility as a function of temperature, or in other words, at higher temperatures the concentration or probability of carbonate precipitation increases. The saturation temperature in all the operational cases is lower than 180 °C (which is a very low temperature to have a carbonate calcium scaling risk). It is also important to note that steam dominated reservoirs in general show lower flow rates when compared to liquid dominated reservoirs and therefore all the dilution, precipitation and formation volume fraction changes presented in the figures below (Figure 11) are very low.

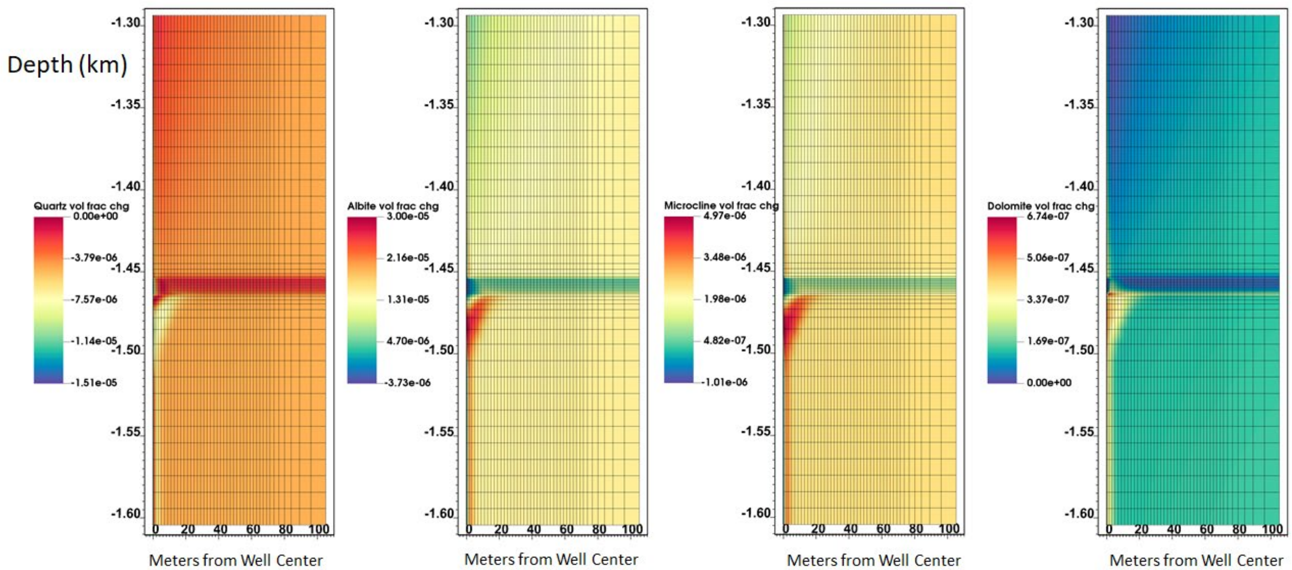


**Figure 11: Quartz, albite, microcline and dolomite volume fraction changes in the near wellbore region at the base of the DBHX are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

At the base of the well the recharge of condensate back into the resource is expected leading to higher liquid saturations as observed in the figure below (Figure 12). The condensate shows a lower pH since HCl, HF and other species are scrubbed from the gas into the condensate. While the condensate recharges back into the resource boiling occurs which leads to high concentrations of solute in the reservoir (higher ionic strength).

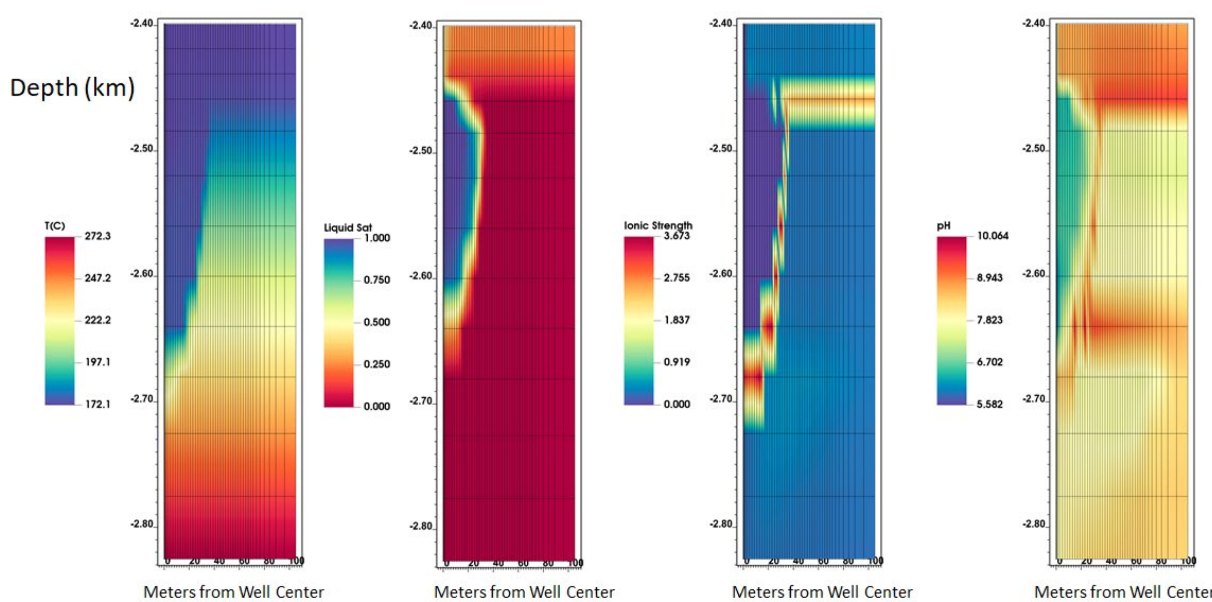


**Figure 12: Temperature, liquid saturation, ionic strength and pH in the near wellbore region at the bottom of the well are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

It is also to be noted that the condensate in the well is more dilute of chemical species and boiling leads to higher concentrations in the reservoir. The order of magnitude of species concentration follow the order: [Cl]>[K]>[$SiO_2$]>[$H_2S$] as observed in the figure below (Figure 13). This is in agreement with the geochemical data for the Clear Lake region (Moore et al., 2000; Donnelly-Nolan et al., 1993).

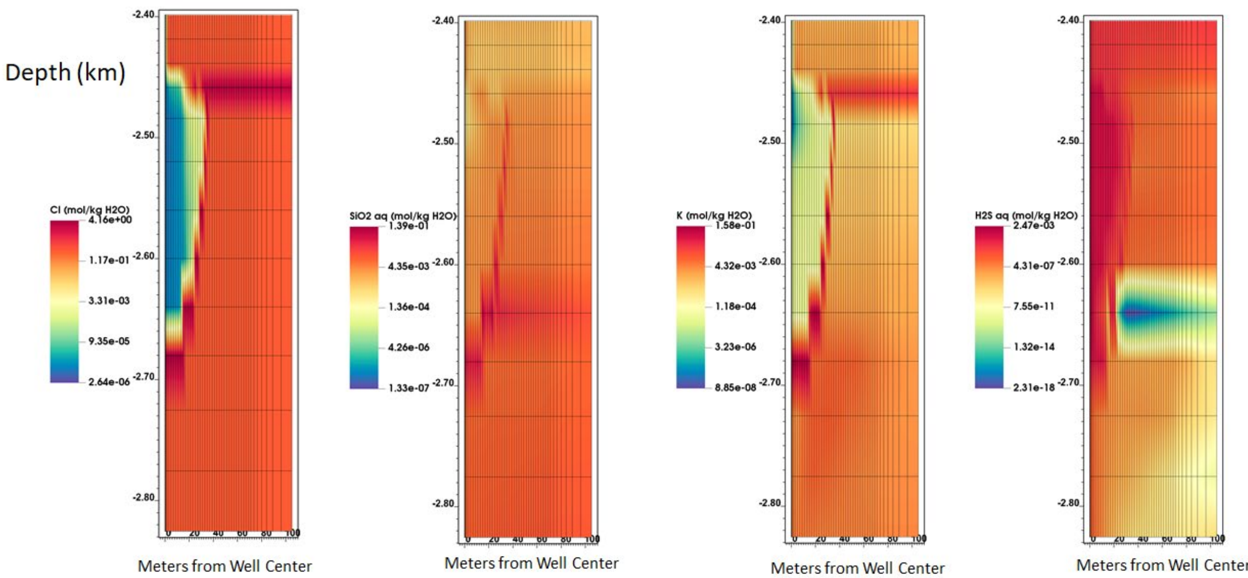


**Figure 13: Cl, $SiO_2$, K, and $H_2S$ concentrations at the base of the well are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

Condensate drainage also causes quartz and calcite dissolution around the open well at the base of the well. Albite and epidote precipitation also occur at the base of the well although at very low volume fraction change as observed in the figure below (Figure 14). These minerals do not represent any risk of scaling due to the equilibrium temperature and the low order of magnitude condensate flow.

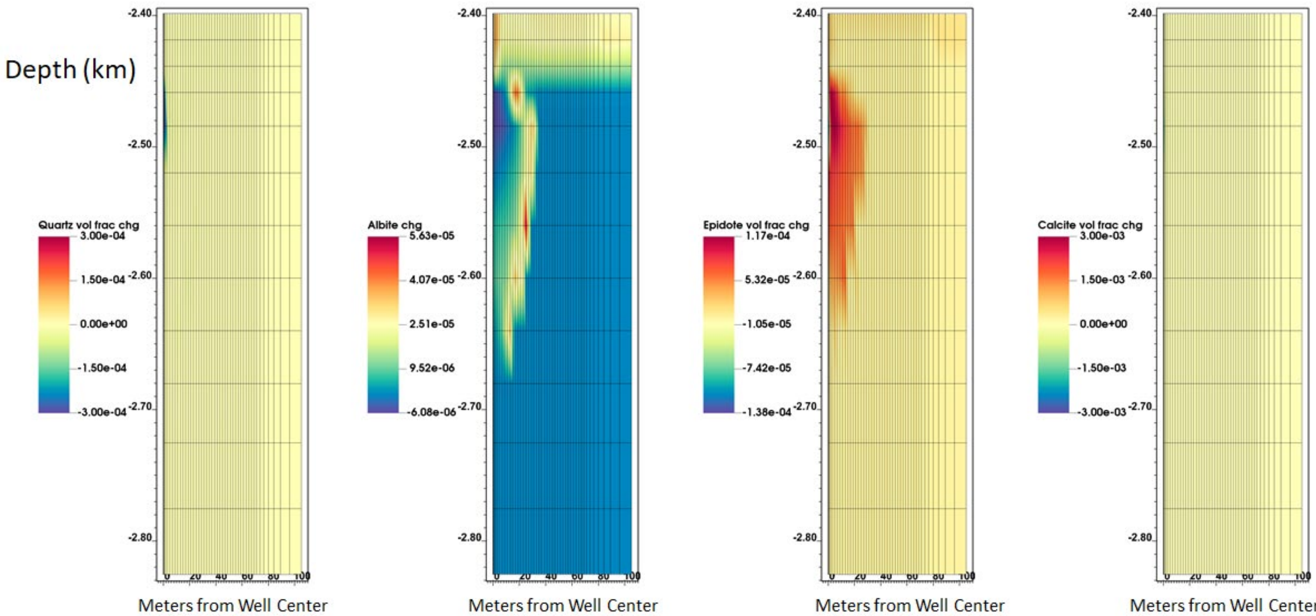


**Figure 14: Quartz, albite, epidote, and calcite concentrations at the base of the well are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

Plagioclase and wairakite dissolution is also caused due to condensate drainage/boiling. Microcline dissolution and precipitation is also formed along with minor dolomite precipitation. These minerals do not represent any risk of scaling due to equilibrium temperature, and order of magnitude of condensate (Figure 15).

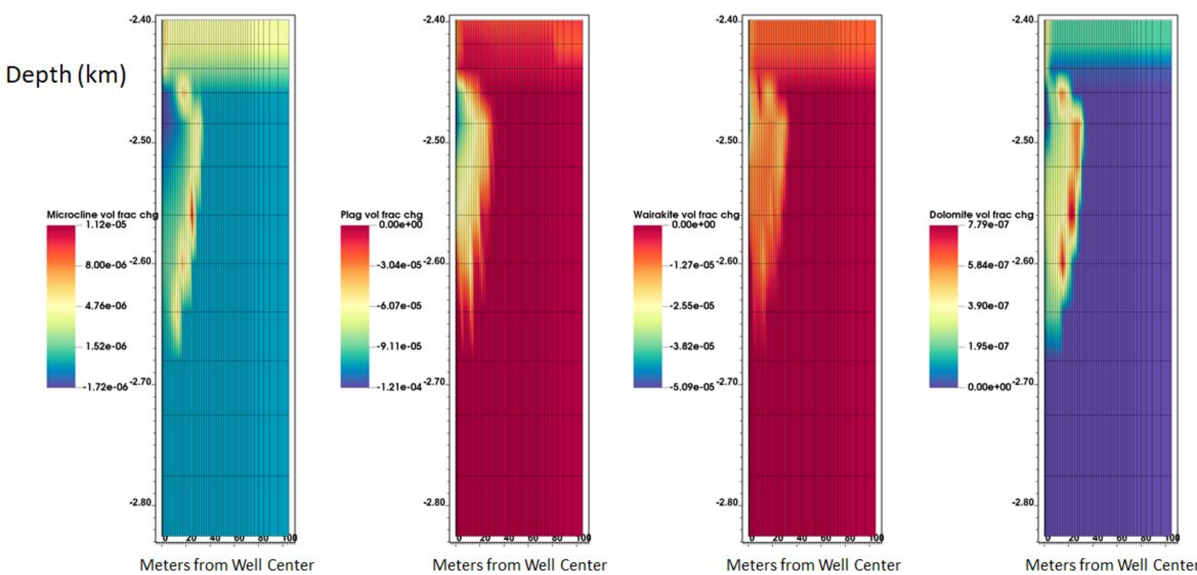


**Figure 15: Microcline, plagioclase, wairakite, and dolomite concentrations at the base of the well are represented after a period of 6 months of continuous operation at the preferred flow rate. The radial axis indicates the distance in meters from the wellbore. The axial direction indicates the depth in km.**

### *3.3 Thermal-Hydraulic-Mechanical (THM) Modeling*

The thermal hydraulic mechanical modeling approach used in this paper was developed and extensively validated for The Geysers geothermal area (Garcia et al., 2016; Rutqvist et al., 2016). The mechanical stress changes and the potential of well integrity along with the micro-seismic effects were studied in detail. In general, geomechanical changes will be driven primarily by pressure and temperature changes. Since no fluid is injected, pressure changes are not significant. In other words, it was found that the geomechanical changes incurred due to the S2PGL system were far less than the changes that would be expected from a typical injection well in The Geysers area such that the resource risk of S2PGL systems will be far less than conventional geothermal systems. Temperature changes were found to be relatively small overall, with the biggest changes of about 30°C cooling at the bottom of the well as observed in the figure below (Figure 16) and an 8℃ cooling in the casing. Temperature changes along the open borehole wall using the S2PGL technology were found to be insignificant for borehole instability.

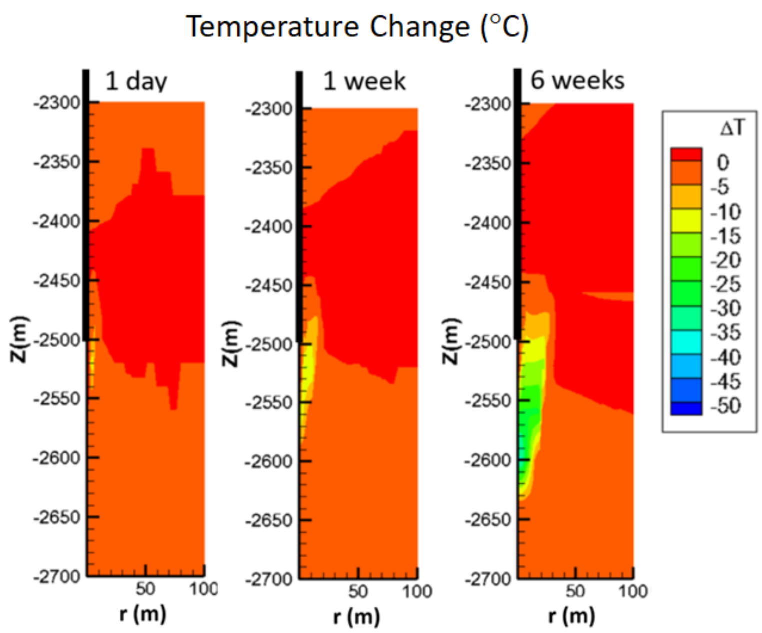


**Figure 16: Temperature change at the bottom of the wellbore as a function of time (1 day, 1 week, and 6 weeks respectively). Cooling in the liquid zone reached steady conditions at around 6 weeks of continuous operation.**

The microseismic potential of the S2PGL was estimated using TOUGH-FLAC based in the approach developed and applied in previous studies of The Geysers (Rutqvist et al., 2016). The stress changes induced by temperature and pressure changes are calculated and using a Coulomb type of criterion, the potential for causing microseismic events are estimated. The criterion have been validated against observed micro-seismicity around injection wells at The Geysers (Rutqvist et al., 2015; 2016). The figure below (Figure 17) shows liquid saturation along with changes in temperature and pressure, and calculated seismic potential after 6 weeks of operation. The seismic potential correlates with the cooling zone below the well, while the pressure changes were found to be low (less than 0.05 MPa) with no significant impact on stress. The micro-seismic volume (dark blue area in the figure below) 150 m height and 100 m horizontal extent is small and would not be expected to induce seismicity that could be felt on the ground. Because the micro-seismic volume is limited in extent, the likelihood of activating larger fractures or faults that could give rise to felt events is small.

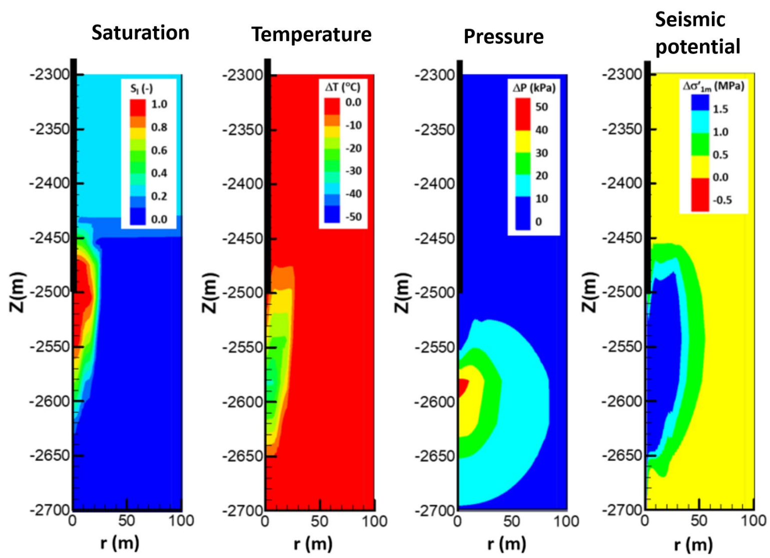


**Figure 17: Liquid saturation, temperature and pressure changes, and seismic potential estimations respectively are represented at the bottom of the wellbore after 6 weeks of operation. The seismic potential correlates with zone of cooling while pressure changes are negligible and have no significant impact stress. The micro-seismic volume is small and would not be expected to induce seismicity that could be felt on the ground.**

The seismic potential and temperature change was also compared with 4 months of continuous S2PGL operation and was found to be very minimal although the zone of temperature and seismic potential expanded from 6 weeks to 4 months as shown in the figure below (Figure 18).

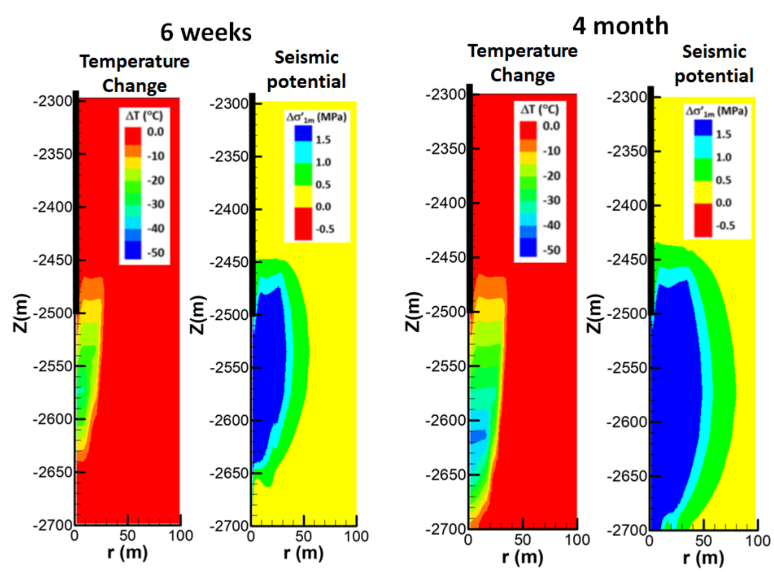


**Figure 18: Temperature change and seismic potential estimations in °C and MPa are represented at the bottom of the wellbore after 6 weeks and 4 months of continuous operation at the preferred flow rate respectively. The micro-seismic volumes in both the scenarios are found to be relatively small.**

The sensitivity of seismic potential to rock elastic modulus was also studied (Figure 19). Even when the rock elastic modulus was increased to 34 GPa from 3.3 GPa, the micro-seismic volume was found to be small. Therefore, the micro-seismic potential was found to be much smaller than typical injection wells required in conventional geothermal technology (Rutqvist et al., 2015; 2016).

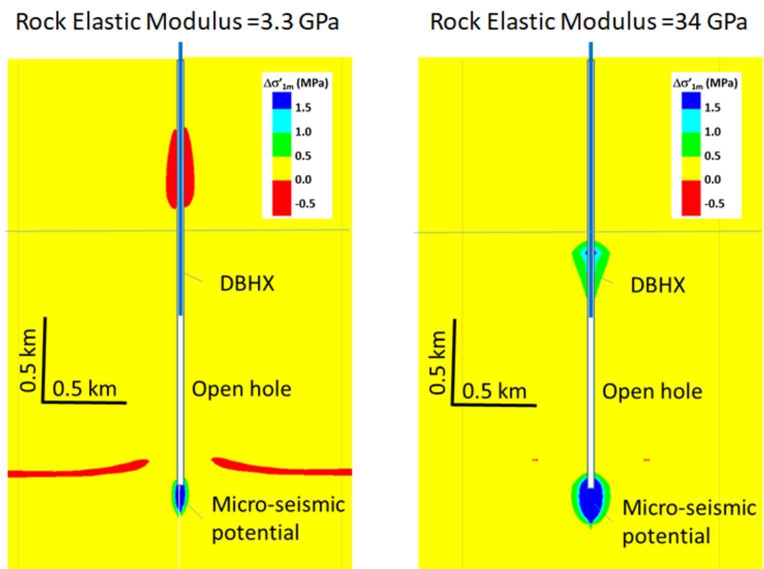


**Figure 19: Sensitivity of seismic potential to rock elastic modulus. It can be observed that the area of micro-seismic influence is very small even when the rock elastic modulus is increased to about 34 GPa from 3.3 GPa.**

## 4. Conclusions

The THMC modeling of the S2PGL technology was developed and simulated for a well in the Southeast Geysers area using TOUGH-REACT and TOUGH-FLAC. At first the native-state conditions of The Geysers resource was developed to capture the observed depth of the liquid cap and steam zone as well as the approximate reservoir pressures and temperatures. The DBHX model in the simulation used was compared with GFE's DBHX model and was found to be in good agreement. Gravity drainage of condensate in the well fills the lower 60-80 meters of the wells and flows by gravity and imbibition into the surrounding unsaturated reservoir rock. THC modeling shows a higher $CH_4$ mole fraction as compared to the $CO_2$ mole fraction in the NCG stream suggesting that $CO_2$, HCl, and HF are scrubbed from the steam into the condensate. Minor dissolution of primary silicates below the wellbore and dissolution/precipitation in rock just below and around the DBHX are also shown through the THC simulations. The net changes in porosity were found to be minor over the 6 month period of simulation and are therefore not expected to impact the S2PGL testing. The THM analysis indicates minor geomechanical impact of the S2PGL operation because temperature and pressure changes are minor in the host rock. The most substantial geomechanical changes are expected to occur at the bottom of the injection well as a result of local cooling, but of smaller magnitude than typical conventional geothermal operations.

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